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Solar Energy Group

May 1983

*Solar Energy Research Institute, Golden, Colorado.

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ABSTRACT

A central solar heating plant with seasonal heat storage in a deep underground aquifer is designed by means of a solar seasonal storage system simulation code based on the Solar Energy Research Institute (SERI) code for Solar Annual Storage Simulation (SASS). This Solar Seasonal Storage Plant is designed to supply close to 100% of the annual heating and domestic hot water (DHW) load of a hypothetical new community, the Fox River Valley Project, for a location in Madison, Wisconsin. Some analyses are also carried out for Boston, Massachusetts and Copenhagen, Denmark, as an indication of weather and insolation effects. Analyses are conducted for five different types of solar collectors, and for an alternate system utilizing seasonal storage in a large water tank. Predicted seasonal performance and system and storage costs are calculated. To provide some validation of the SASS results, a simulation of the solar system with seasonal storage in a large water tank is also carried out with a modified version of the Swedish Solar Seasonal Storage Code MINSUN.

*Solar Energy Research Institute, Golden, Colorado

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1. INTRODUCTION

The heating and hot water requirements of dense urban neighborhoods, particularly in the northern, northeastern and midwestern regions of the U.S.A., are a primary consumer of fossil fuels and a source of heavy urban air pollution. The attempt to meet a significant portion of this heating load and to reduce pollution by the utilization of solar energy in the usual single residence, diurnal cycle system is extremely difficult and is unlikely to be cost effective in this region because of very high winter loads combined with generally low winter insolation. A similar, and perhaps even more critical, situation exists in most of Europe and in Canada.

However, even in countries with the most severe unbalance between winter load and insolation, such as Sweden, a substantial quantity of solar energy is available during the summer, spring, and fall seasons. A solar system which is designed to collect and store this energy for utilization during winter months can be a viable and cost effective source of winter heating. A number of analyses[1-4] have demonstrated quite reliably that a large, seasonal storage solar system can supply a given heating load with 30 to 70% less collector area than a set of small diurnal solar systems supplying the same load. In addition, such large systems, utilizing a large central collector field, a large underground storage subsystem, and a modern, low temperature heat distribution system, can be built readily in urban environments, offer considerable economies of scale, can be cost effective, and can cleanly provide close to 100% of a given large, high density load[2,4].

In response to this mutual need, and in recognition of the high potential for success, an International Energy Agency (IEA) program was begun in January 1980 to exchange information and cooperate in the design, analysis, construction and operation of solar seasonal storage systems. This was Task VII on Central Solar Heating Plants with Seasonal Storage (CSHPSS) of the IEA Solar Heating and Cooling Program. Nine countries (Austria, Canada, Denmark, Germany, the Netherlands, Sweden, Switzerland, the United Kingdom, and the United States) plus the Joint Research Center (JRC) of the Commission of European Countries (CEC) in Ispra, Italy, are participating in this Task VII.

One of the earlier activities of Task VII was the selection and development of a simulation/optimization code for the design and analysis of CSHPSS systems. The primary code chosen for this purpose was the Swedish solar seasonal storage code MINSUN.[5] However, in its existing form this code was not adequate for the design of the wide variety of CSHPSS system configurations of interest to the participating countries. Consequently, a considerable number of modifications and improvements have been and are still being made in this code.[6] During this period of code development a number of base case CSHPSS systems were chosen and analyzed as a means of testing the code, training operators and comparing results between nations. Following upon this, each participating nation selected a National Test Case (NTC), either a hypothetical or an actual CSHPSS design of particular interest to itself. These NTCs were simulated and analyzed with existing nation CSHPSS simulation codes and, where possible, with the then current version of MINSUN (several iterations of these NTC analyses were and are being made with successive improved versions of MINSUN). The U.S.A., as part of this exercise, formulated a U.S.A. NTC called the Fox River Valley Project. This was a hypothetical new community of commercial and residential buildings, essentially identical to one section of a project designed, with a co-generation-district heating system for heating, cooling, hot water and electricity, for construction in the Fox River Valley Region close to Aurora, Illinois.[7] For the purposes of this study the CSHPSS project was analyzed for a Madison, Wisconsin location, since this is considered more favorable for solar seasonal storage systems and since Madison was one of the standard climatic locations chosen by Task VII for comparative analyses. In addition, some analyses were also performed for an identical project located in Boston, Massachusetts, and in Copenhagen, Denmark, in order to assess weather and insolation effects. These two latter cities are also standard Task VII climatic locations. Analyses were performed for five different collector types (flat plate, commercial vacuum tube, advanced CPC vacuum tube, parabolic trough, and central receiver), for two different storage methods (aquifer and tank), and for a range of values of the significant design and economic parameters. Seasonal performance, and system and storage costs were calculated in each case.

Since the MINSUN code did not, and still does not, have the capability to simulate the performance of a solar heating plant with seasonal storage in an aquifer, these analyses were performed with a simulation code based on the U.S.A. Solar Annual Storage Simulation (SASS) Code developed at the Solar Energy Research Institute (SERI) in Golden, Colorado.[8] This code was modified by installation of the MINSUN weather-insolation-collector processor UMSORT,[6] and by addition of a linear-graphical simulation model of aquifer performance developed by LBL.[9] However, in order to have some cross reference between SASS and MINSUN analyses, a number of simulation runs of the Fox River Valley Project with seasonal storage in a tank were carried out with both SASS and MINSUN. A complete, detailed set of simulation and sensitivity analyses of the Fox River Valley Project with an underground concrete seasonal storage tank are currently being conducted with the latest version of MINSUN, and will be reported at a later date.

2. SYSTEM DESCRIPTION AND LOAD

2.1 Community Description

The United States Task VII participants are designing a National Test Case (NTC) solar seasonal storage system for a hypothetical community in Madison, Wisconsin which is modeled on a zone of The Fox River Valley project in Illinois[7]. The geographic layout is presented in Figure 1. Approximately one third of the community consists of the high density town center, with commercial and public buildings comprising a total floor area of about 2.2×10^4 m^2, and with high and mid-rise apartment buildings containing 446 units of 5.2×10^4 m^2 total floor area. The remainder of the zone is low density residential with 750 town houses and 408 garden apartments having a total floor area of 1.3×10^5 m^2. The distribution of building types is 89% residential and 11% commercial.

The community buildings are assumed to utilize standard present day construction methods with no special energy conserving features not commonly in use in the U.S.A. For the purpose of this design-analysis a uniform average degree-hour space-heating load coefficient of 0.429 MWH per degree day centigrade, referred to 18°C, and an internal gain of 1500 KW is assumed, with a further assumption of zero heating load in June, July and August. The DHW load is assumed to be constant at 24 MWh/day (1000 KW) throughout the year.

2.2 Location and Climate

Madison, Wisconsin is located at latitude 43°8'N, longitude 89°20'W, at an altitude of 262 meters above sea level. It is approximately 70 miles west of Lake Michigan, and has several small lakes in its immediate vicinity. The area is generally flat glacial terrain, underlaid by a number of aquifers and clay layers at various depths. The project site will be a reasonably close-in suburb of the city, where some new housing development is underway (so that roads and utility services are available, but where land prices have not experienced too high a speculative escalation).

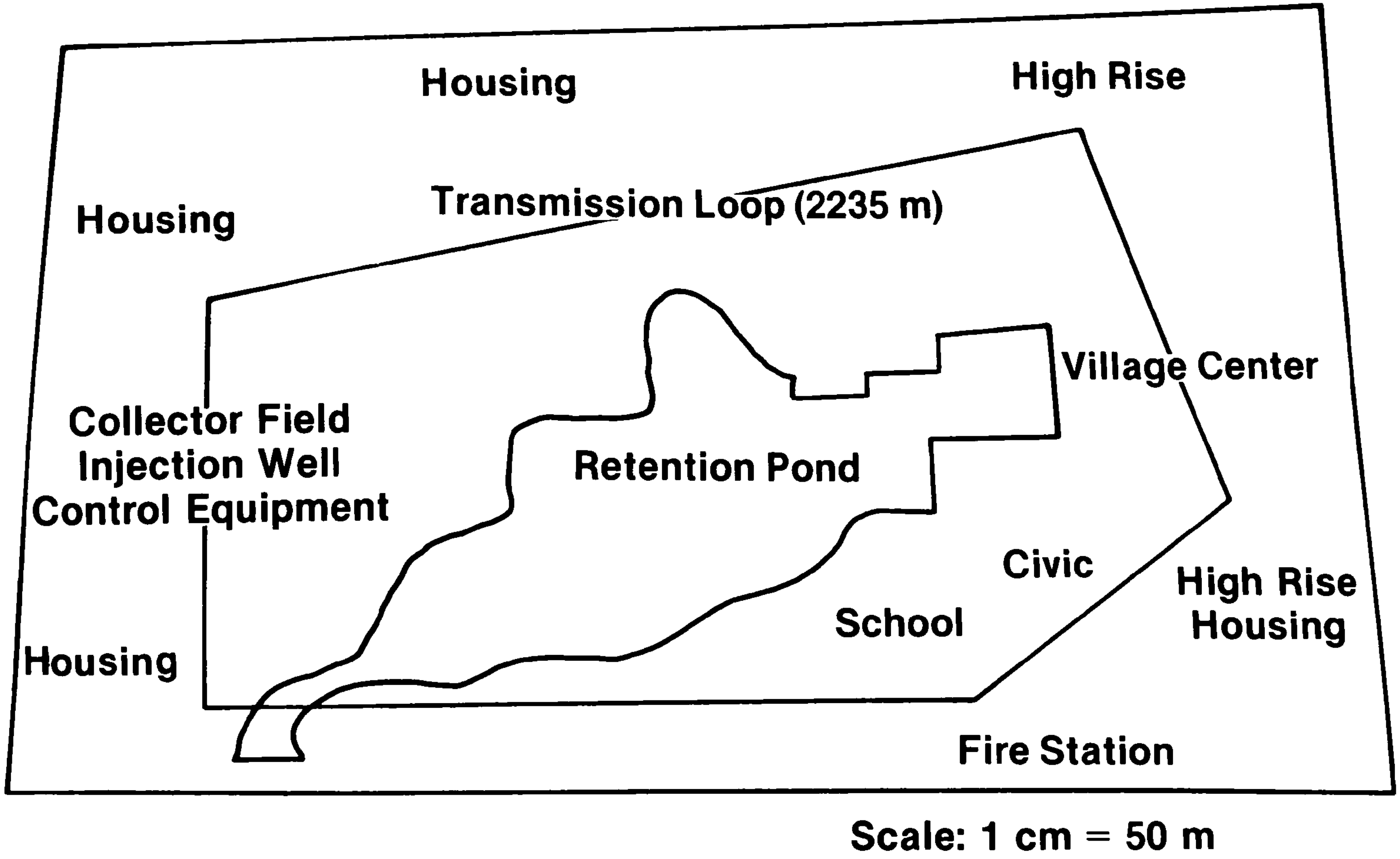


Figure 1. Geographical Layout of the Fox River Valley NTC

The seasonal variation and annual weather and insolation conditions are given in Tables 1 and 2 below:

Table 1. Average Seasonal Weather

	JAN	APR	JUL	OCT
Wind (m/s)	5.2	5.7	3.8	4.8
Sky Cover (%)	60	56	47	52
Precipitation (m)	0.036	0.069	0	0.008
Snowfall (m)	0.241	0.038	0	0.008
Relative Humidity (%)	77	66	70	70

Table 2. Monthly and Annual Insolation and Temperatures

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Daily Radiation MJ/SQ m.	5.85	9.12	12.89	15.87	19.78	22.11	21.95	19.38	14.75	10.34	5.72	4.41	13.52
Average Daytime Temp. Deg. C	-7.0	-5.0	0.5	9.2	15.2	20.6	23.0	22.3	17.3	11.8	2.9	-4.3	8.9
Average Daily (Temp. Deg. C)	-8.4	-6.5	-1.0	7.4	13.3	18.8	21.2	20.4	15.4	9.9	1.5	-5.6	7.2
C. Degree Days (Ref. 18°C)	830	696	599	328	165	40	8	22	96	263	505	742	4294

2.3 Load

For purposes of this design, space heating and domestic hot water load data simulated for the Fox Valley community were examined in three forms: design day hourly energy requirements, from which were derived peak power loads; monthly total energy requirements; and annual energy requirements.

The design day temperature for Madison was taken as -10°F. The maximum power required at the load on the design day is then 17.0 MW. Design day data are plotted in Figure 2, and are listed in detail, by building type, in Table 3. The monthly and annual space heating, DHW and total load data are presented in Table 4. The monthly domestic hot water load for the entire community is based on a constant usage of 24 MWhr/day. The total annual load is then 54.6×10^3 MWh. The annual space heating and DHW loads are 45.8×10^3 MWh and 8.8×10^3 MWh, respectively.

Note that the analyses for Boston and Copenhagen are based on different loads, which are calculated for the climates of those cities.

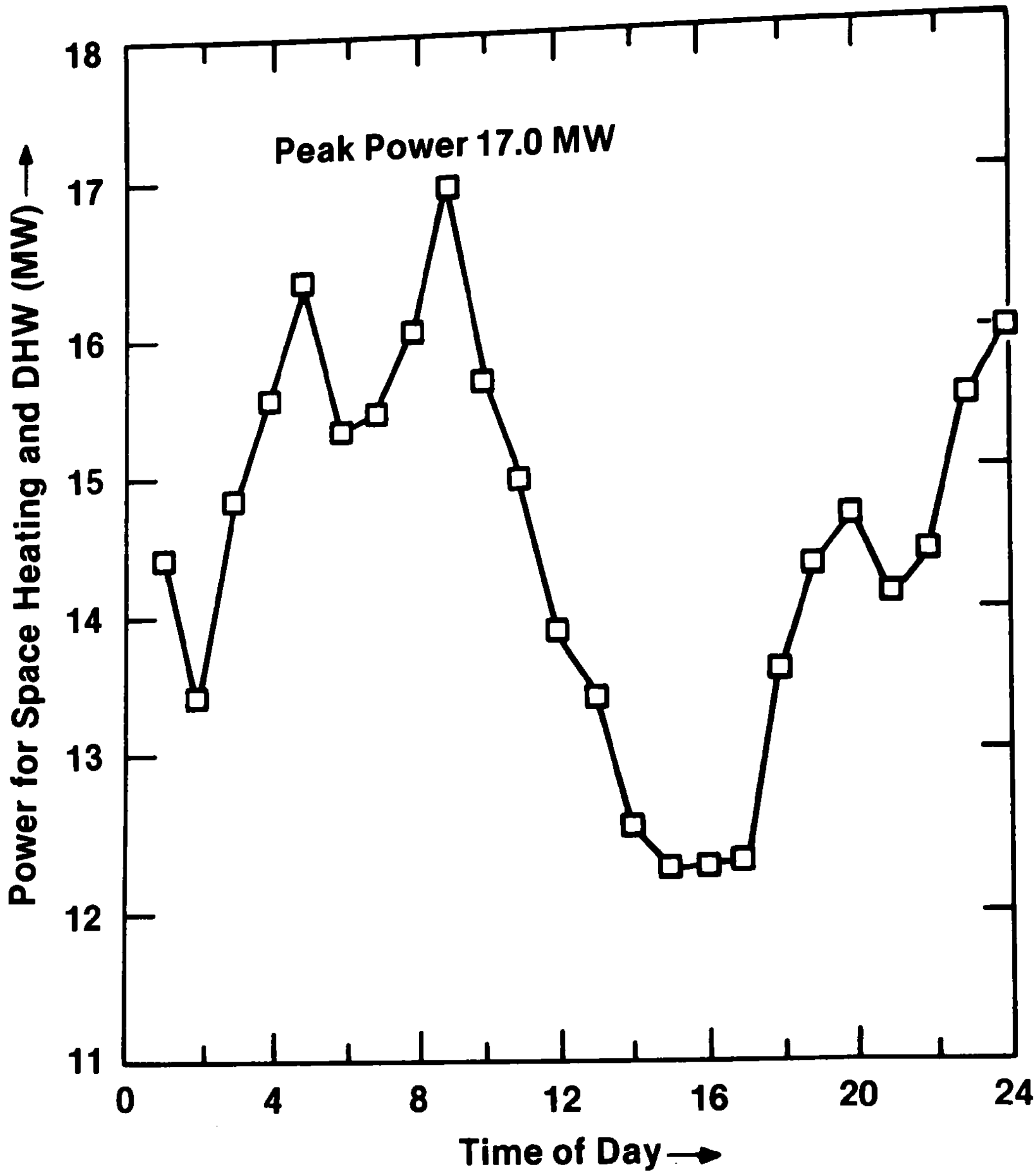


Figure 2. Design Day Power Requirements

Table 3. Design Day Space Heating and DHW Loads

Time of Day	Mid-rise Apartment		Fire Station		School Zone		Town Center		Low-rise Apartment		Total Loads		Total
	Heat	DHW	Heat	DHW	Heat	DHW	Heat	DHW	Heat	DHW	Heat	DHW	
1	262	47	7	.7	4.7	0	101	0	929	91	1304	138	1442
2	300	38	6	.5	4.7	0	101	0	826	73	1235	112	1347
3	337	28	7	.4	7.1	0	121	0	929	55	1401	83	1484
4	374	38	7	.5	9.4	0	121	0	929	73	1440	112	1552
5	374	28	7	.4	18.9	0	121	0	1032	55	1553	8.34	1636
6	337	38	7	.5	23.6	0	121	0	929	73	1418	112	1530
7	300	47	7	.7	23.6	0	142	0	929	91	1402	139	1541
8	300	47	7	.7	18.9	0	202	0	929	91	1457	139	1596
9	262	94	7	1.4	16.5	0	202	.7	929	182	1417	278	1695
10	262	85	6	1.2	11.8	.3	202	4.1	826	164	1308	255	1563
11	262	76	6	1.1	7.1	2.4	162	6.8	826	146	1263	232	1495
12	225	66	6	.9	7.1	3.4	121	6.8	826	128	1185	205	1390
13	225	66	6	.9	7.1	1.0	81	4.1	826	128	1145	200	1345
14	187	57	6	.8	7.1	.7	61	4.1	826	109	1087	172	1259
15	187	47	6	.7	7.1	1.0	61	4.1	826	91	1087	144	1231
16	187	47	6	.7	7.1	.7	61	4.1	826	91	1087	144	1231
17	187	47	6	.7	9.4	.3	61	6.8	826	91	1089	146	1235
18	225	57	6	.8	9.4	0	121	6.8	826	109	1187	176	1353
19	225	76	6	1.1	9.4	0	142	4.1	826	146	1208	227	1435
20	262	76	6	1.1	7.1	0	142	4.1	826	146	1243	227	1470
21	262	66	6	.9	4.7	0	121	0	826	128	1220	195	1415
22	300	57	6	.8	23.6	0	121	0	826	109	1277	167	1444
23	300	57	7	.8	23.6	0	121	0	929	109	1381	167	1548
24	337	66	7	.9	23.6	0	101	0	929	128	1398	195	1593

Table 4. Monthly Energy Demand
(MWhr/Month)

	Heating Load	DHW	Total
January	9141	744	9885
February	7532	672	8204
March	6959	744	7703
April	3391	720	4111
May	1829	744	2573
June	0	744	744
July	0	744	744
August	0	744	744
September	1100	720	1820
October	2890	744	3634
November	5373	720	6093
December	7581	744	8325
Total	45796	8784	54580

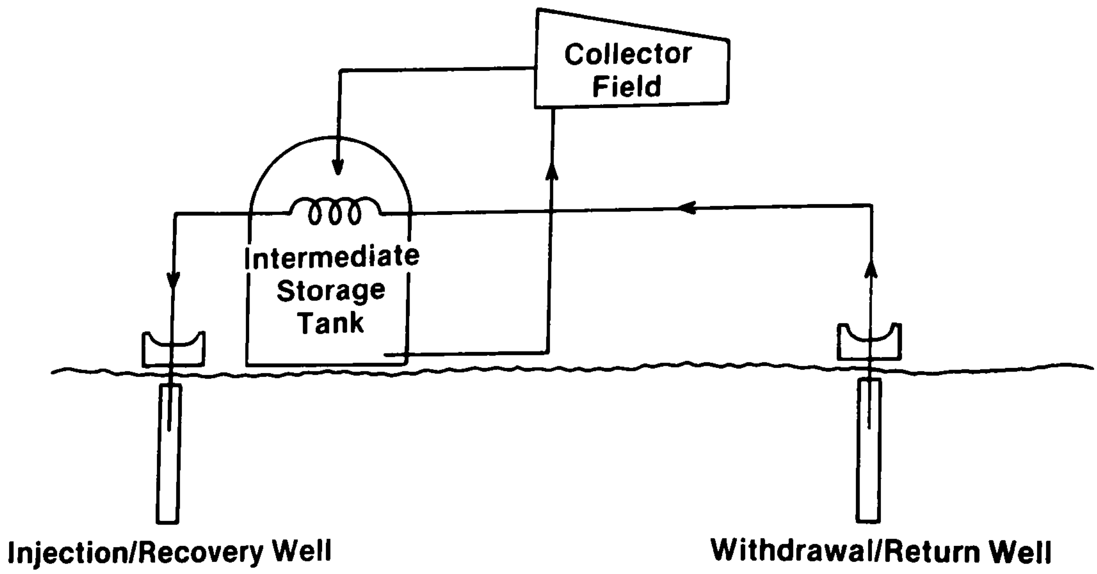
2.4 Overall System Description

A central field of collectors feeds hot water, via a buffer-daily cycle storage tank, either directly into the distribution loop or into an aquifer which has its charge and discharge wells located close to the collector field. The distribution system is a two-pipe closed loop system with flow in either direction, with a zero point at the end opposite from the collector field. No details regarding the building heat distribution network have been determined. Distribution temperature is tentatively set at 52°C. Water is delivered to the distribution system from the diurnal tank, which is heated by the collectors and/or the aquifer storage. The solar system will be sized to supply from 90% to 100% of the load. When insufficient heat is available from either source to maintain the supply water at 52°C or above, an auxiliary supply, which may be either a fossil (natural gas) fired boiler or heat pump, is turned on.

A variety of system configurations and control strategies, which are identical during the summer (and some portion of spring and fall) charging-of-storage period, but differ during the winter discharging and load supply season, were investigated. The basic and common configuration during summer charging is shown in Figure 3. During summer operation the aquifer is charged with water at a temperature between 85°C and 82°C. The holding or intermediate storage tank is used as a thermal integrator. Injection into the aquifer proceeds when the tank temperature reaches or exceeds 85°C and terminates when the temperature falls below 82°C. This strategy allows essentially constant temperature injection of water. Aquifer water is entirely separate from collector fluid.

The simplest configuration for winter operation MODE A, which was used for the bulk of the analyses carried out in this study, is shown in Figure 4.

Figure 3. Summer Operation (MODE A,B,C - No Load)



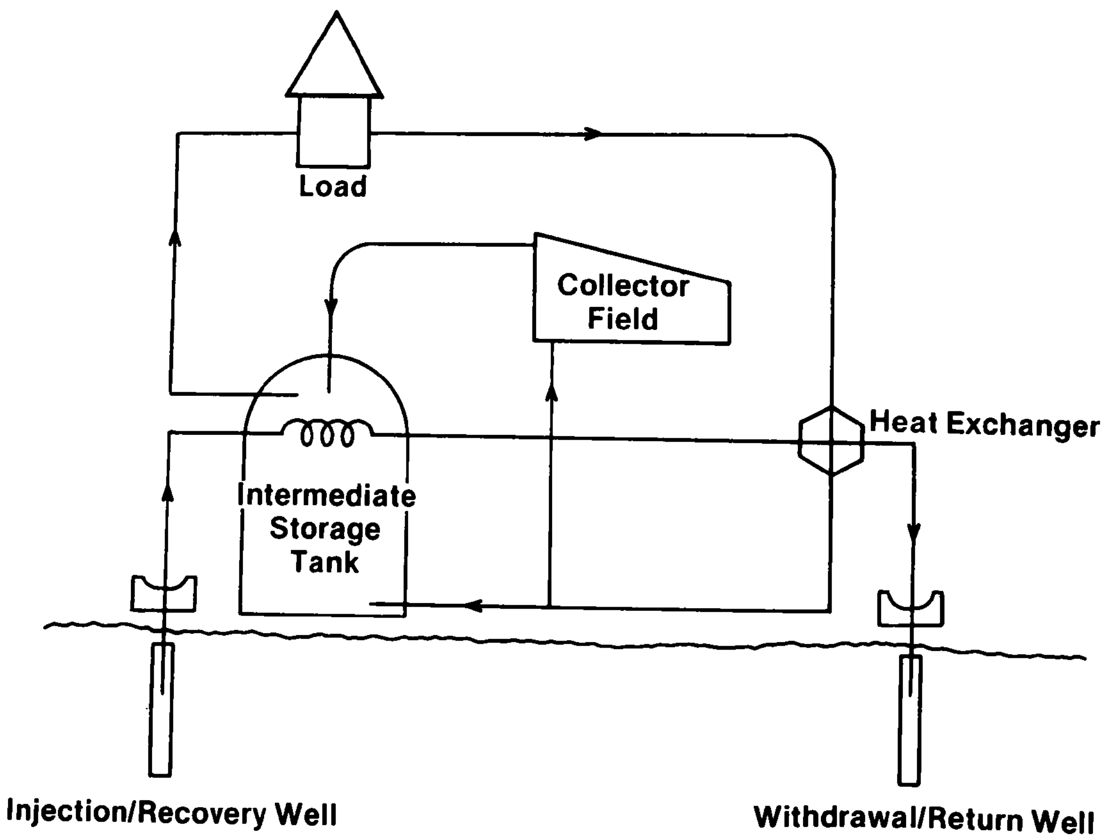


Figure 4. Winter Operation (MODE A)

During winter operation with MODE A the collector field feeds energy at temperatures of 52.5°C (125°F) directly into the piping to the load. When the collector output temperature falls below this value, energy for the load is drawn from the holding tank. When the temperature of the holding tank falls below 52.5°C, energy is recovered directly from the aquifer. When the recovery temperature falls below 52°C auxillary energy must be added. A heat exchanger is used between the distribution return line and the return well line to raise the input temperature to the tank. While this results in decreased collector efficiency more energy is recovered from the return line.

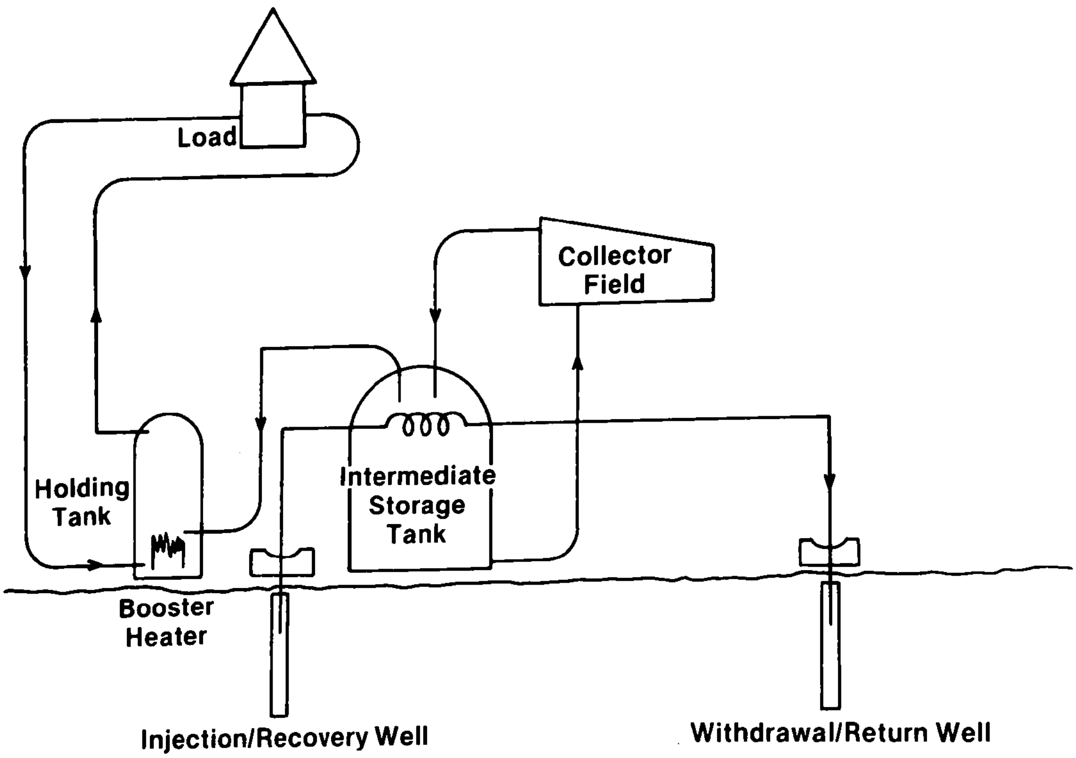
The MODE A configuration was simulated for two different operational conditions, as follows:

1) An annual cycle system using MODE A operation during first year charging of the aquifer was simulated. The initial ground water temperature was taken to be 11°C (52°F). The average injection temperature into the aquifer was taken to be 85°C (185°F). No useful energy was extracted below 52°C (125°F).

2. The operation of the solar thermal utility following five years of charging and discharging was simulated. The average temperature of withdrawal of ground water was taken as 42°C (108°F).

An alternate configuration strategy, MODE B, for winter operation is illustrated in Figure 5. In MODE B operation a second holding tank is added to improve collector efficiency and to allow energy to be drawn out from the aquifer at what would be a less than useful temperature in MODE A operation. In this study this useful temperature is chosen to be 38°C (100°F). However, only a limited number of simulations of MODE B operations were conducted. In these runs the temperature of the source ground water was taken as 11°C.

Figure 5. Winter Operation (MODE B)



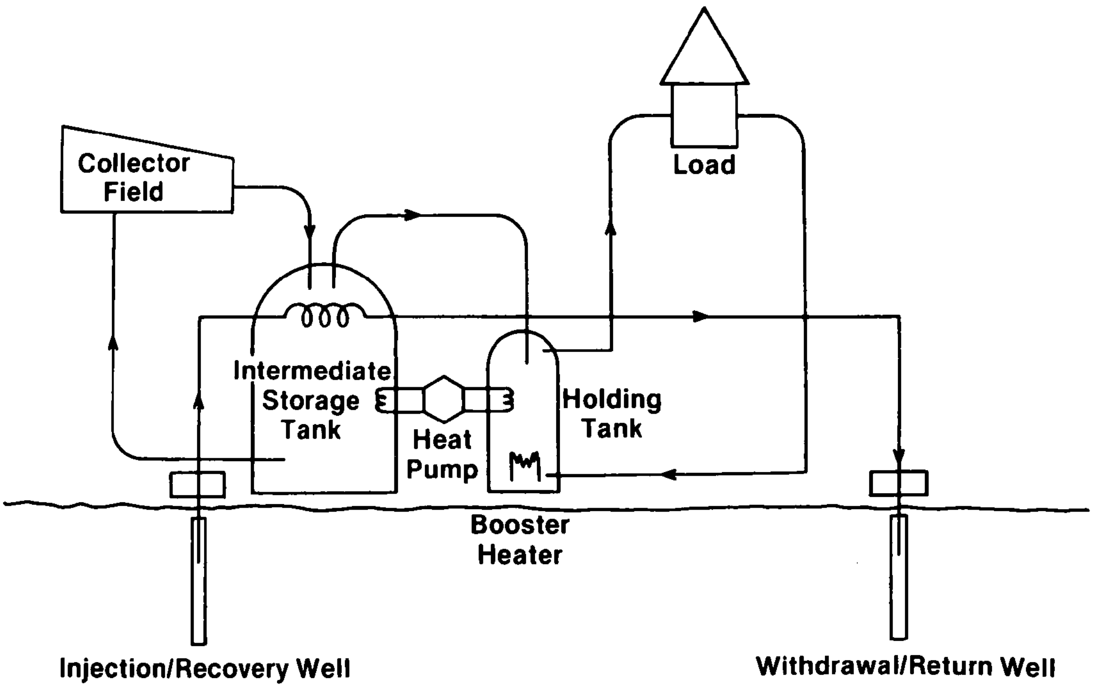


Figure 6. Winter Operation (MODE C)

By linking the Intermediate Storage Tank and the Holding Tank of MODE B via a heat pump, it becomes possible to draw the intermediate storage tank and the aquifer storage down to a much lower temperature, thereby increasing collector efficiency and storage recovery. This MODE C winter operation is shown in Figure 6. However, since SASS did not contain a heat pump module, no simulation of this operational mode was conducted.

3. SUBSYSTEM CHARACTERISTICS

3.1 Aquifer Specifications

The primary seasonal heat storage subsystem selected for the Fox River Valley National Test Case is a deep, confined aquifer. Several potentially usable confined aquifers underlie the Madison area; however, data is not presently available on these aquifers. Consequently, for the purposes of our preliminary design, we utilized the well-defined characteristics of the relatively nearby "Franconia-Ironton-Galesville formations" aquifer underlying Minneapolis-St. Paul, Minnesota, which is presently being utilized in a DOE sponsored aquifer seasonal thermal energy storage field test[10]. An artist sketch of the aquifer structure is shown in Figure 7. A summary of hydraulic and thermal properties of the selected formations are given in Table 5. The listed parameters are favorable for aquifer thermal energy storage, but are certainly not optimal. Geologic systems exist in a wide variety of locations within the United States that would have equal or better characteristics.

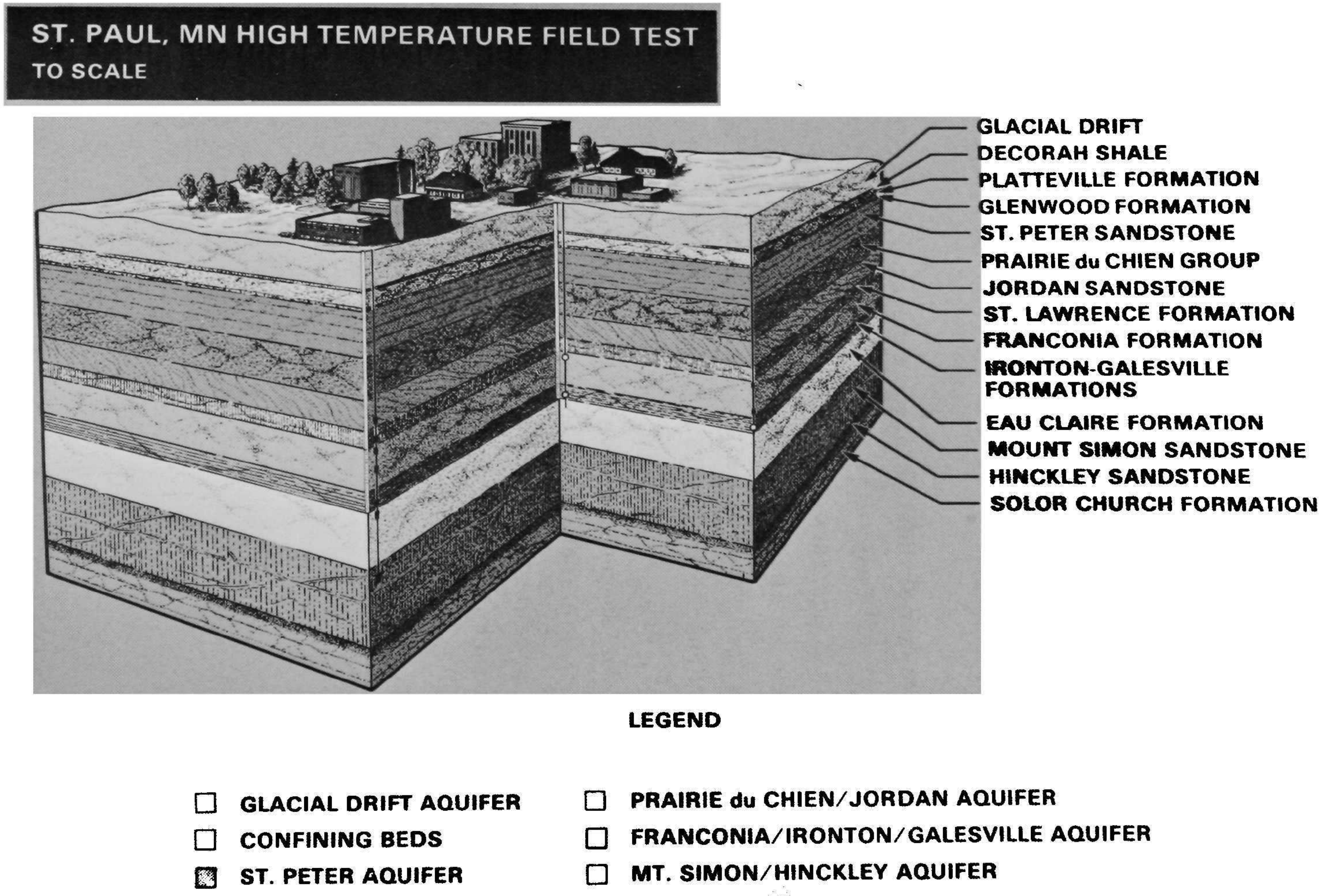


Figure 7. St. Paul Minnesota High Temperature Field Test Aquifer

Table 5. Aquifer Hydraulic and Thermal Characteristics

Aquifer thickness (assumed to be under artesian conditions and isolates top and bottom by nearly impermeable strata)	70 feet
Depth (below land surface)	400 feet
Aquifer Horizontal Hydraulic Conductivity	15 ft/day
Aquifer Vertical Hydraulic Conductivity	1.5 ft/day
Aquifer Porosity	0.20
Aquiclude Thickness (top and bottom)	50 feet
Aquiclude Horizontal Hydraulic Conductivity (top and bottom)	0.1 ft/day
Aquiclude Vertical Hydraulic Conductivity (top and bottom)	0.01 ft/day
Aquifer Thermal Conductivity (sandstone-unsaturated value)	30 BTU/ft. day°F
Aquifer Heat Capacity (sandstone - same)	25 BTU/ft^3 °F
Aquiclude Thermal Conductivity	25 BTU/ft day °F
Aquiclude Heat Capacity	25 BTU/ft^3 °F
Water Heat Capacity	1.0 BTU/lb °F
Reservoir Fluid Pressure	100 psia
Permeability	Determined @ 20°C
Storage Coefficient	1×10^{-4}

3.2 Aquifer Performance Modeling

Conventional means of heat storage frequently fall into a standard pattern of performance. There is a storage medium with a defined heat capacity, volume, and heat loss rate, and daily interaction between storage, collectors,and load. In a simulation of annual storage systems, the storage component is analyzed by calculating a daily heat balance. Net heat flow into the storage component is calculated as the sum of heat input, heat removal for the load, and heat lost from storage. The daily change in storage temperature may then be calculated based on storage capacity and this net heat flow. Storage volume is of course a constant, and the key parameter for system analysis is the storage temperature.

Aquifers differ from this conventional storage component model in a number of ways. In the first place, aquifer systems can not be modeled as an interaction between a collection/distribution system and a storage medium of constant volume. Rather, the volume of hot water introduced into the aquifer is increased as heat is collected in the summer,and the stored hot water is removed from the aquifer as heat is needed in the winter. The most important parameter is not the storage temperature, but the storage volume. Storage temperature is not found through a heat balance equation, but rather from an aquifer temperature profile. It is the change in volume of stored water that is calculated through the heat balance.

A second difference in the simulation of aquifer performance is that aquifer heat losses are a complex function, depending on a number of physical factors within the aquifer. There is no simple term for daily storage heat loss; the storage processes may be understood only in terms of the season-long aquifer processes.

The analysis of aquifer performance used in this study is based on work by Doughty, Hellstrom, Chin Fu Tsang, and Claesson[9]. This work presents an analysis of aquifer performance in the following scenario. Hot water at a fixed temperature is introduced into the aquifer at a constant rate for a three-month period. Next, the aquifer water is assumed to be stored for three months, without interaction with the rest of the system. In the third three-month period, water is withdrawn from the aquifer at a constant rate for use by the load. Finally, in the last three month period, the emptied aquifer stands idle, with the cycled water stored in the cool-storage well. This cycle represents a summer charging period, fall storage, winter discharging, and a spring idle time.

Based on this situation, Doughty's analysis presents a profile of aquifer temperature versus time for the winter discharging period, assuming constant rate of withdrawal of heat from the aquifer. These temperature profiles are dependent on three dimensionless parameters which are used to characterize the individual aquifer: the Peclet number (P_e), the Lambda number (Λ), and the ratio of thermal conductivities (λ_a/λ_c). A plot of the generated temperature profiles is shown in Figure 8 (from Reference 9).

A number of problems arise in adopting these results for aquifer performance to the design of a complete system. In an aquifer storage system, both the periods of injection of aquifer water and the periods of retrieval are likely to be longer than three months. Furthermore, the injection temperature may not be constant. What will aquifer performance be under these conditions? Specifically, there is one open question concerning the reported aquifer temperature profile: should the temperature profiles reported by Doughty et. al. be viewed as linked to the time of year, even if the withdrawal period is longer than three months, or should the temperature profile be linked to the quantity of water withdrawn from the aquifer? Since the withdrawal rate is constant over time in Doughty's analysis,the reported aquifer temperature profiles may be viewed either as being time-dependent or volume-dependent.

It was decided that the aquifer temperature profiles reported by Doughty will be used in the simulation as a function of the quantity of water withdrawn, and not as a function of time. This decision is somewhat arbitrary, and reflects unknown factors in aquifer performance. However, if time were to be used as the parameter for determining aquifer temperature, there would be difficulties in determining the appropriate time period that

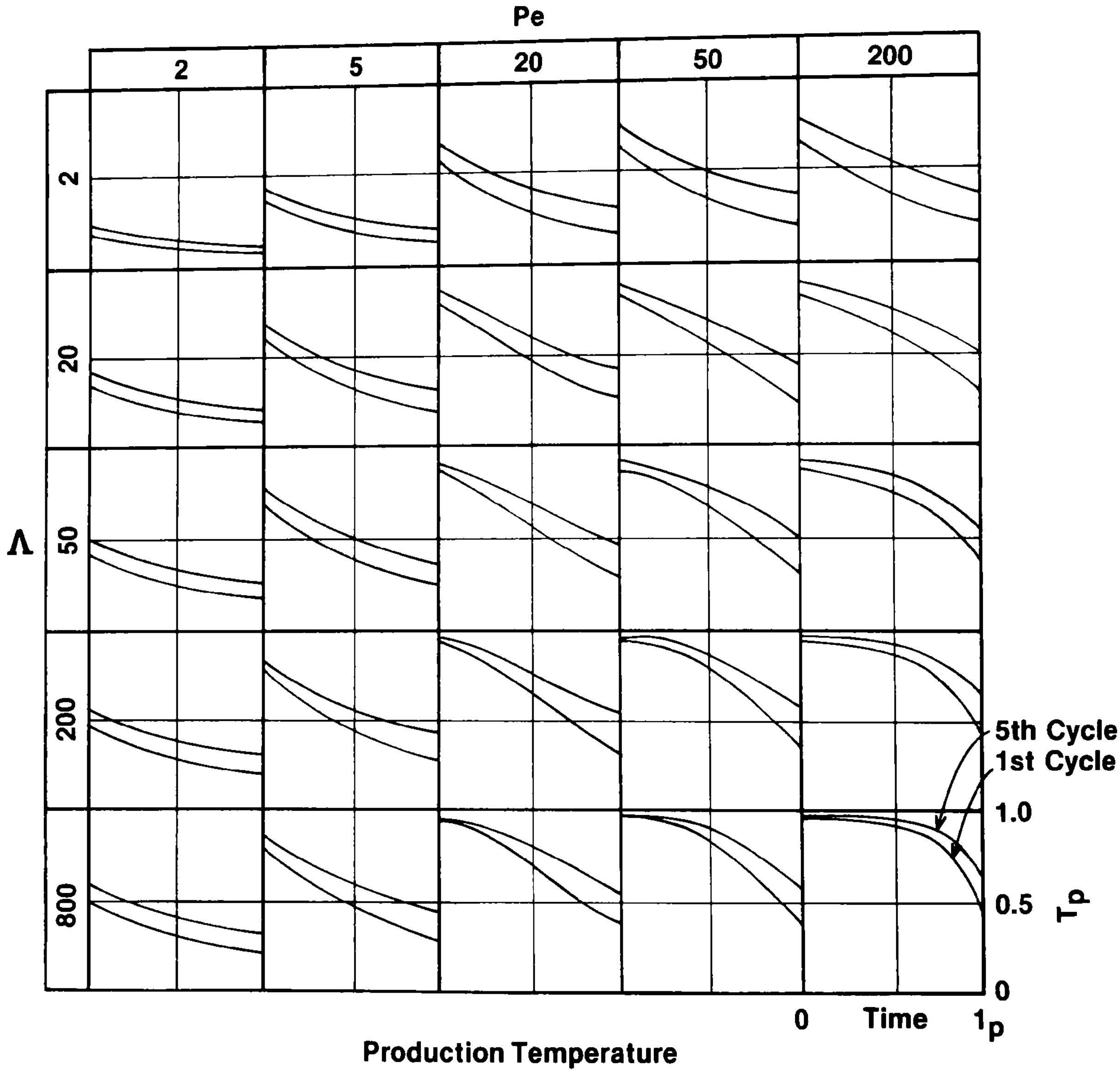


Figure 8. Aquifer Temperature Profiles (from Reference 9). First and fifth cycle production temperatures versus time for a range of Pe and Λ when $\lambda_a/\lambda_c = 2$.

the temperature profile is linked to. When the temperature profile is linked instead to the rate of withdrawal, the profile is automatically adjusted to reflect the proper time period.

The Peclet number and other aquifer parameters, based on geographical characteristics of the Minnesota-Wisconsin region, were found by Charles Kincaid of Pacific Northwest Laboratories.[11] The numbers are:

$$P_e = 99.5/\varepsilon$$

$$\Lambda = 31.5$$

$$\lambda_a/\lambda_c = 1.67$$

where ε is the aquifer storage efficiency, approximately 0.67. The appropriate temperature profile was found from Doughty's work assuming an injection temperature of 85°C and a ground temperature of 15°C. The actual temperature profile was found to be a linear pattern, with the aquifer temperature varying from 82°C to 52°C.

It was also decided to assume the use of a diurnal cycle storage tank in conjunction with the aquifer and the solar collection system. The resulting configuration, previously referred to as MODE A, is shown in Figures 3 and 4. Use of a diurnal tank is justified for the following reasons:

1. Without a diurnal tank there would be frequent day-to-day cycling of the aquifer storage system, especially in the spring and fall months. It is not known what the effect of rapid cycling would be on aquifer performance. The pumping cost of repeated cycling is also unknown.

2. A diurnal storage tank would not add significantly to the cost of the entire system, and would have many advantages from the point of view of system control.

3. Use of a "two-tank" system, with both diurnal and annual storage, results in a significant performance advantage over a single unstratified annual storage tank. Since the aquifer cannot be stratified, the two-tank concept may be advantageous there also. This is reported on more fully in a recent work by Sillman.[1]

3.3 Collector Subsystems

A total of five different collector types were studied. These are: flat plate,evacuated tube, advanced CPC evacuated tube, parabolic trough and central receiver. The performance for each of these collector types is calculated with the MINSUN-UMSORT Routine[6] by the following equation:

$$E = F_R\ (\tau\alpha)\ K_{\tau\alpha} - F_R U_L\ (T_i - T_{amb})/I$$

$$- (F_R U_L)^2\ (T_i - T_{amb})^2/I^2$$

where $k_{\tau\alpha}$ is the incident angle modifying factor for insolation angles other than normal. The parameter values used for each collector type are given in Table 6 below.[6]

3.4 Distribution Subsystem

Most hot water distribution systems in Western European countries are designed for a maximum supply line temperature of 110-130°C (230 to 266°F) and for a return line temperature of 50-70°C (122 to 158°F)[12]. Choice of an aquifer injection temperature of 85°C (185°F) places an unusual constraint upon the operation of the distribution system.

Table 6. Collector Parameter Values

Collector Type	F_R	$F_R U_L$	$(F_R U_L)^2$	$K_{\tau\alpha}$
Flat Plate	0.808	4.33	0.00	0.10
Evacuated	0.510	1.30	0.00	0.17
Advanced CPC	0.70	1.00	0.00	0.17
Parabolic Trough	0.807	0.089	0.869	0.00
Central Receiver	0.980	0.00	0.00	0.00

We have chosen a distribution temperature of 52°C (125°F). Such a choice allows possible use of innovative non-corrosive materials such as fiberglass reinforced plastic, cross-linked polyethylene, polybutylene, or prestressed or polymer concretes. However, the design of the heat delivery system is less flexible. Attention must be paid to use of heat exchangers which have a sufficient drop in temperature. A central temperature control strategy cannot be used without a fossil fuel backup heater to boost system temperatures on colder days. A variable flow control method such as is employed in Japanese district heating systems, should probably be incorporated into our design. This may prove somewhat difficult.

If we assume that the heat exchangers are designed to provide a 15°C temperature drop at the load, then from the relation $v = \dot{Q}/c_p \Delta T$, a volumetric water flow of approximately 0.2 m^3 per second is required to meet the 17 MW thermal peak load. If we keep below the typical maximum range distribution piping flow velocity of 3.5 m/second, the main line piping diameter required is 0.25 m, which is not unreasonable.

4. SIMULATION MODELS AND METHODS

4.1 Use of MINSUN

The MINSUN computer code would require major modification to be used with an aquifer storage system. The MINSUN code uses a heat balance equation to model the storage component, and calculates the storage temperature distribution at the end of each day. As explained above, such a calculation is inappropriate for an aquifer, where the important parameter is not storage temperature but storage volume. Furthermore, the storage temperature in an aquifer system does not have the same effect on the other system components as storage usually does (i.e. aquifer temperature is not linked to collector inlet temperature). Consequently, a modification of MINSUN to model aquifer systems would require not just an additional storage component model, but would require changing the interaction between the storage subsystem and other components of the model. Finally, MINSUN at present cannot be used with a diurnal storage tank, as would be required by the current aquifer system design (MODE A). It was concluded that the use of MINSUN for the U.S. National Test Case would require major modifications which are beyond the scope of this study.

4.2 The SASS Code

Instead, the SERI Annual Storage Simulation (SASS) Code was modified for use with an aquifer. The SASS simulation code, described elsewhere[1,8], is a simple daily-step simulation for both diurnal and annual storage systems. Because it is a very simple model, it is easy to modify for an aquifer system. In the modified version of SASS, a conventional solar heating system with diurnal storage is modeled. However, when the diurnal storage tank reaches 85 C., excess heat is not dumped, but is stored in the aquifer. As explained above, the volume of water stored in the aquifer is to be calculated based on the amount of heat available to heat aquifer water from 11°C or 42°C (the temperature of the cold storage well in the first or sixth year of operation) to 85°C. When the storage tank temperature exceeds 85°C, the heat exchange between storage and aquifer depicted in Figure 3 is activated. The tank storage temperature is assumed to decrease to 79.4°C, while water entering the aquifer is assumed to increase from 11°C or 42°C to 85°C. Based on this heat exchange and the heat capacity of water, the volume of water added to the aquifer is calculated. In the winter, heat is extracted from the aquifer whenever the storage tank temperature drops below 52°C. The temperature of the extracted aquifer water is found from the aquifer temperature profile discussed above. The aquifer water drops to 42°C in the course of heat exchange, and is stored in the cool storage well. The volume of aquifer water extracted is again calculated based on this heat exchange, as the volume necessary to heat the storage tank to 52°C.

Note, that in the course of this calculation, the modified SASS simulation not only calculates system performance, but also finds the required volume of the aquifer in order to store all available heat. The total quantity of water introduced into the aquifer is calculated by summing the individual additions. As will be discussed below, the optimal system sizing is most likely one with an aquifer large enough to store all excess summer heat. Thus the problem of optimal sizing is greatly simplified--the simulation itself calculates the proper aquifer size for a given collector area. Note also that the aquifer temperature profile and other system control and heat exchange arrangements used in the simulation may be modified to reflect the physical properties of different aquifers, and to reflect different system configurations.

There are two problems with the use of the SASS code for the design of the U.S. National Test Case. One problem is that the SASS code was originally designed only for simulation with flat-plate and evacuated-tube collectors, and could not simulate the performance of many collectors used in this study. A second problem is that the SASS simulation results may not be comparable to the results of MINSUN, used by the other IEA Task VII study participants. In order to solve both these problems, a further modification of the SASS code was done to enable the SASS program to run with data generated by UMSORT, the MINSUN preprocessor. (Normally, SASS runs on its own preprocessed radiation data). In this way, the SASS code may be run for any collector type that has been included in MINSUN, and generates MINSUNconsistent results. A discussion of our experience with the SASS code and with MINSUN, along with a validation of the modified SASS code against the MINSUN code is presented in the Appendix.

5. RESULTS

5.1 Preliminary Analyses

As a first attack on the design problem, in order to roughly compare the different configuration-operation strategy MODES (A & B) and to obtain a preliminary system sizing and performance, simulations were performed for a system with aquifer storage, for only three collector types (flat plate, evacuated tube and parabolic trough), for Madison, Wisconsin, for MODE A operation (Figures 3 and 4) in the first year and after five years of operation, and for MODE B operation (Figures 3 and 5) in the first year of operation. A system simulation for a solar system with dispersed diurnal storage designed to meet 40-70% of the load was also performed for comparison purposes.

The collector area,solar contributions (fractions) from both the aquifer and the collectors, the overall solar fractions, and the average aquifer efficiencies are listed in Table 7, for three types of collector in each of the three configurational-operational modes.

These preliminary simulation results are also plotted in Figures 9 through 11 together with the results of the diurnal system simulation. It is evident that once a decision is made to use aquifer thermal energy storage then the efficiency of storage should be maximized by choosing an optimal control strategy. The graphs demonstrate that MODE A operation requires a substantial amount of backup energy in charging from performance on curve a (first year) to that on curve b (sixth year). Also, the unity solar fraction points on curves b and c (MODE B) are identical because at this point no backup is required even with MODE B operation and thus effectively the aquifer is used only down to 52°C. The main difference between MODE A and B operation is that the charging to curve c (MODE B, first year) takes substantially less energy than charging from curve a to b (MODE A, first to sixth year).

The slopes of curves c and b become less positive as solar fraction unity is approached. The optimal point depends on the trade-off between the price of backup energy and collectors. Our initial estimate was that a system using either flat plate or evacuated tube collectors would have an economic optimum at 90% solar fraction. The system using parabolic troughs could be driven at close to unity solar fraction. Another consideration is the yearly variation in load. A system designed with an adequate backup to meet 10% of the load would easily manage extra cold winters.

5.2 Aquifer System Final Sizing and Economic Analysis

System sizing was performed for the MODE A configuration in the sixth year of operation, using the modified SASS code for five collector types -- flat plate, evacuated tube, advanced CPC collector, parabolic trough, and central receiver. The analysis for Madison was also repeated in part for the other two I.E.A. Task VII standard test sites, Boston and Copenhagen. In each case, aquifer systems were designed assuming the aquifer is large enough to store all collected solar energy. The performance of diurnal solar systems for the same collector array, load, and control strategy is also calculated for comparison with the aquifer system. Diurnal tank size in cubic meters is set as one tenth the size of the

Table 7. Preliminary Simulation Results

Control Strategy	Collector Type	Collector Area (1000m^2)	Solar Fraction: Collectors (%)	Solar Fraction: Aquifer (%)	Overall Solar Fraction (%)	Aquifer Annual Thermal Efficiency (%)
MODE A First-Year	Evacuated tube	50	36	8	42	38.4
		80	49	15	64	39.3
		100	56	20	76	38.4
		120	62.7	25.1	87.8	
	Flat plate	50	37	8	45	38.5
		80	49.4	15.2	64.6	39.7
		100	56.2	20	76.2	38.9
		120	62.3	25.4	87.7	38.2
	Parabolic trough	25	36.2	9.1	45.3	38.6
		40	50	17.5	67.5	38.6
		50	57.5	23.7	81.2	41.2
		60	64.2	29.6	93.8	39.6
MODE A Sixth-Year	Evacuated tube	50	36	14	50	67.4
		80	49	26	75	68.4
		100	56	35.6	91.6	67.5
		120	62.7	36.8	99.5	54.7
	Flat plate	50	37	14.5	51.5	69.2
		80	49.4	27	76.4	
		100	56.2	36.3	92.5	68.2
		120	62.3	37.3	99.6	
	Parabolic trough	25	36.2	16.5	52.7	
		40	50	32	82	70.6
		50	57.5	41.9	99.4	68.6
MODE B First-Year	Evacuated tube	50	36.4	15.2	51.6	80.6
		80	49.1	29.4	78.5	81.2
		100	55.8	39.2	95.0	76.8
	Flat plate	50	38.5	15.8	54.3	81
		80	50	30	80	81
		100	56	39	95	76
		120	62	37.5	99.5	86.4
	Parabolic trough	25	36	18	54	
		40	50	35	85	82
		50	57	42	99	70.6

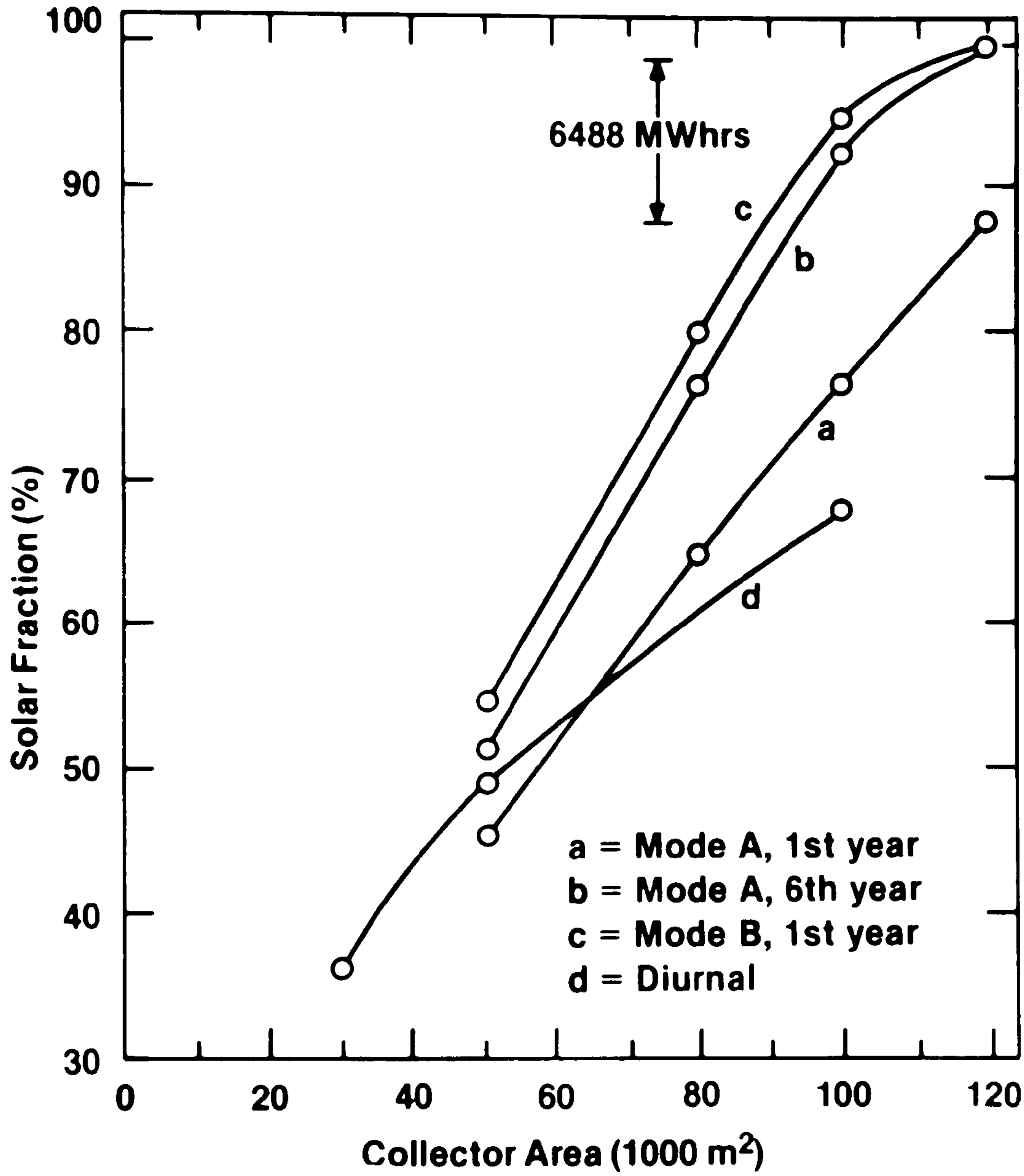


Figure 9. System Performance Flat Plate Collectors

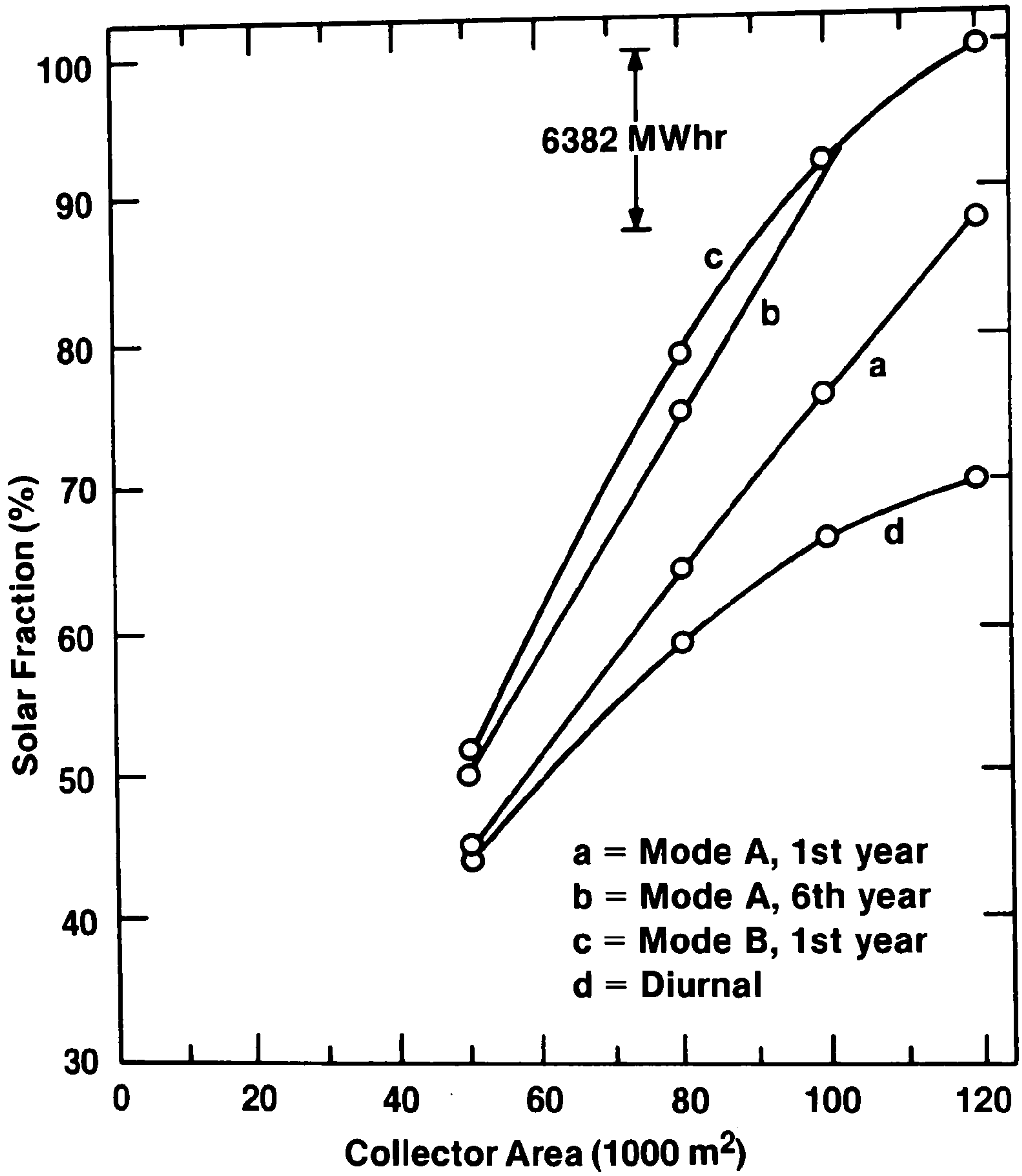


Figure 10. System Performance Evacuated Tube Collectors

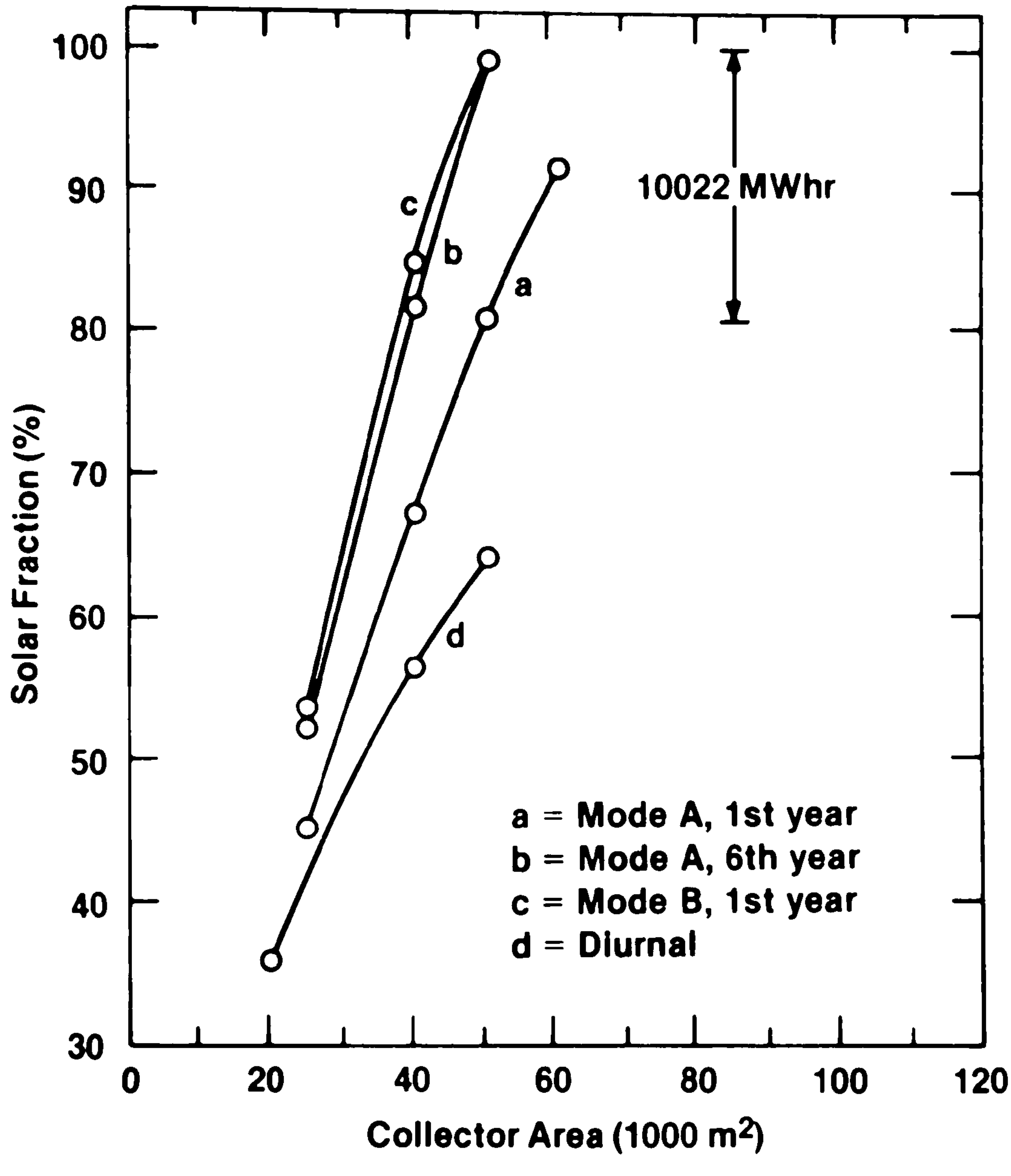


Figure 11. Systems Performance Parabolic Trough Collectors

collector array in square meters. Thus, a 100,000 m^2 array would have a diurnal tank, both as part of the aquifer system and in the diurnal system, of 10,000 m^3 volume.

In addition, comparable system designs are presented for certain systems with storage in constructed tanks instead of the aquifer. The tank systems were analyzed using both MINSUN and the SASS design code.

Collector performance parameters were those specified by Zinko and Hakanssen in an earlier I.E.A. Task VII study.[13,6] Use of the MINSUN preprocessor insures that collector performance will be comparable to the other studies of this Task VII series.

Along with system performance, an economic analysis is presented for each of the system simulations. The economic analysis is somewhat unusual. It relies on the calculation of a system break even cost, which is defined as the cost of alternative fuel (in ¢/kWh) needed to make the solar heating system a break-even economic investment when compared to an equivalent conventional HVAC system. The system break even cost is calculated as follows: Total energy supplied by the system is found from the simulation results. Total system cost is calculated. The break even cost is the cost of energy which, when applied to the quantity of energy delivered annually by the system, results in an expense equivalent to the total system cost based on a life-cycle costing analysis.

Cost assumptions are as follows. For flat plate and evacuated tube collectors, \$170/m^2 including piping and installation. For advanced CPC collectors, parabolic troughs, and central receivers, \$250/m^2. These costs are taken to reflect future cost goals for collectors.* Present collector

*The projected future cost goals for CPCs, parabolic troughs, and central receivers are actually all below \$200/m^2. However these projected costs seem extremely inexpensive. The \$250/m^2 figure was taken as a less optimistic base for comparison.

costs[13] are probably too high to be cost effective for all except flat plate collectors (possibly). The assumed cost of storage is $20/m^3 for the aquifer[14], $35/m^3 for large annual storage tanks, and $200/m^3 for diurnal tanks. The aquifer cost figure is necessarily imprecise, the actual costs will be linked to the cost of drilling individual wells rather than to the actual storage capacity. The diurnal storage cost is somewhat high for the district-scale diurnal storage tanks, but it is selected to reflect the cost of heat exchangers and controls as well.

Analysis of the distribution system has not been performed in detail. Prior experience suggests that the cost and performance of the distribution system will be a major factor in system viability. In the Inglestad 50 residence system[15] which was used recently as a test case for the MINSUN simulation, distribution losses accounted for one third of the total system load, and a significant share of total system cost. However the Madison system is designed for a high-density district, and the distribution system will be proportionately smaller. Based on the district size, it is estimated that a district heating grid of 3000 meters length, with pipe diameters of 0.25 meters, will be required. Using MINSUN to analyze the cost and performance of this grid, with standard cost assumptions ($100/m pipe length, $100/m^3 insulation material, and 5 cm. insulation thickness), it was found that the total distribution system cost is $1.2 million. Distribution losses were found to be only 3% of the total system load. These assumptions were used in the simulation.

Finally, the parameters used for the economic life-cycle costing analysis are:

Discount rate: 10% above inflation
Fuel escalation rate: 4% above inflation
System lifetime: 20 years

These assumptions result in a present worth factor (defined as the ratio of present value to annual payment) of 11.5. These assumptions are more stringent than the standard IEA Task VII assumptions of 4% interest and 2% fuel escalation above inflation, which would result in a present worth factor of 16. (Note that the higher interest rate penalizes the solar systems, but the higher fuel escalation rate improves its cost effectiveness relative to a conventional systems).

Complete results for all systems, in the three cities, are presented in Table 8. Table 8 includes the following information:

- Collector area (in 1000 m^2)
- Storage volume, assuming the aquifer is large enough to store all collected energy (in 1000 m^3)
- Solar fraction (the percentage of the load met by solar)
- Diurnal solar fraction (The solar fraction that would be supplied by a diurnal system without the aquifer)
- Diurnal system break even cost
- Storage system break even cost
- Total system break even cost

The storage break even cost is a break even cost computed for the storage component alone. It is calculated by computing the difference between energy supplied by the total system and energy supplied by the diurnal system. This difference is taken as the amount of energy "supplied" by the annual storage. Break even cost is computed by counting this amount of energy against the cost of the annual storage system.

Table 8. System Performance, Sizing and Economics
Madison, Wisconsin
(Load 54,600 MWH)

Coll. Area (1000 m^2)	Aquif. Vol (1000 m^3)	Solar Fractn.	Diurnal Solar Fractn.	Breakeven Costs (Cents/KWH) (Diurnal)	(Stor.)	(Total)
FLAT PLATE COLLECTOR						
75.	259.	.548	.446	5.5	8.1	6.0
100.	385.	.694	.524	6.1	7.2	6.4
125.	532.	.832	.587	6.8	6.9	6.8
150.	691.	.969	.639	7.4	6.7	7.2
EVACUATED TUBE COLLECTOR						
75.	268.	.559	.437	5.6	7.0	5.9
100.	406.	.717	.521	6.2	6.6	6.3
125.	569.	.871	.590	6.7	6.4	6.6
140.	674.	.958	.628	7.1	6.5	6.9
ADVANCED CPC COLLECTOR						
30.	120.	.361	.308	4.8	7.2	5.2
50.	282.	.568	.435	5.4	6.8	5.7
70.	461.	.763	.532	6.0	6.4	6.1
90.	677.	.948	.614	6.6	6.5	6.6
PARABOLIC TROUGH						
40.	215.	.491	.384	5.0	6.4	5.3
60.	412.	.717	.502	5.5	6.1	5.7
80.	626.	.923	.601	6.0	6.2	6.1
85.	683.	.974	.623	6.2	6.2	6.2
CENTRAL RECEIVER						
60.	465.	.746	.503	5.5	6.1	5.7
70.	581.	.854	.552	5.8	6.1	5.9
80.	709.	.962	.596	6.1	6.2	6.1

Table 8. (Continued)
Copenhagen, Denmark
(Load 49,700 MWH)

Coll. Area (1000 m^2)	Aquif. Vol (1000 m^3)	Solar Fractn.	Diurnal Solar Fractn.	Breakeven Costs (Cents/KWH) (Diurnal)	(Stor.)	(Total)
FLAT PLATE COLLECTOR						
100.	145.	.605	.548	6.4	8.9	6.7
130.	231.	.724	.616	7.4	7.5	7.4
170.	370.	.880	.693	8.5	6.9	8.1
200.	476.	.977	.742	9.2	7.1	8.7
EVACUATED TUBE COLLECTOR						
100.	201.	.651	.550	6.4	7.0	6.5
125.	304.	.774	.613	7.1	6.6	7.0
150.	418.	.896	.670	7.8	6.5	7.4
160.	464.	.941	.720	7.7	7.3	7.6
ADVANCED CPC COLLECTOR						
75.	275.	.725	.577	6.5	6.5	6.5
100.	461.	.917	.663	7.4	6.4	7.1
110.	536.	.988	.693	7.8	6.4	7.4
PARABOLIC TROUGH						
60.	284.	.720	.566	5.4	6.5	5.6
75.	426.	.874	.629	6.0	6.1	6.0
80.	475.	.923	.651	6.1	6.1	6.1
85.	525.	.971	.672	6.3	6.1	6.2
CENTRAL RECEIVER						
50.	244.	.651	.510	5.0	6.1	5.3
60.	349.	.764	.562	5.4	6.0	5.6
70.	457.	.873	.607	5.8	6.0	5.9
80.	566.	.977	.649	6.1	6.0	6.1

Table 8. (Continued)
Boston, Massachusetts
(Load 44,000 MWH)

Coll. Area (1000 m^2)	Aquif. Vol (1000 m^3)	Solar Fractn.	Diurnal Solar Fractn.	Breakeven Costs (Cents/KWH) (Diurnal)	(Stor.)	(Total)
FLAT PLATE COLLECTOR						
75.	236.	.609	.490	6.2	7.8	6.5
100.	355.	.766	.570	7.0	7.2	7.0
125.	480.	.914	.639	7.7	6.9	7.5
140.	568.	.990	.676	8.1	7.1	7.8
PARABOLIC TROUGH						
50.	289.	.654	.454	6.4	5.7	6.2
60.	380.	.770	.532	6.5	6.3	6.4
70.	472.	.887	.586	6.8	6.2	6.6
80.	567.	.975	.636	7.1	6.2	6.8
ADVANCED CPC COLLECTOR						
50.	260.	.621	.468	6.2	6.7	6.3
60.	340.	.726	.518	6.6	6.5	6.6
70.	424.	.831	.570	7.0	6.4	6.8
80.	508.	.932	.625	7.2	6.5	7.0
82.	525.	.952	.633	7.3	6.5	7.0

5.3 Discussion of Aquifer System Results

The breakeven costs may be interpreted as follows. Whenever the actual alternative fuel cost is greater than the diurnal (or total) system breakeven cost, then the diurnal (or total) system is cost-effective. Whenever alternative fuel costs are greater than the storage component breakeven cost, then it is worth including annual storage in the system. If the storage component breakeven cost is too high, this means that it is preferable to build a diurnal system without annual storage. For the annual storage system to be economically advantageous, the cost of alternative fuel must be higher than both the total system cost and the storage component breakeven cost.

Based on the breakeven costs in Table 8, and neglecting solar fractions, an optimization analysis for flat plate collector systems in Madison might go as follows: If alternative fuel costs less than 5.5¢/kWh, then no solar system is economically competitive. For fuel costs of 5.5¢ to 6.8¢ per kWh, the economically optimal system is a diurnal system with the collector area varying from 75,000 m^2 to 125,000 m^2, depending on the fuel cost. For a fuel cost of 6.9-7.2¢/kWh, the optimum system is an aquifer system with 125,000 m^2 collector, and for fuel costs above 7.2¢/kWh, the optimum becomes a 150,000 m^2 aquifer system. However, one mighty alternatively, considering solar fractions, argue that for fuel costs of 6.8¢/kWh or above,an aquifer system providing 83% solar is preferable to the diurnal system which supplies only 59% solar. Also, since it may be desirable to specify some minimum solar fraction, the comparison of breakeven costs can depend on this specified minimum. Thus, for the evacuated tube collector in Madison for instance, the diurnal system supplying 44% to 52% solar at breakeven costs of 5.6 to 6.2¢/kWh might seem optimal. However, if a minimum solar fraction of about 60% were desired the aquifer system is clearly more economical (6.6 to 6.9 ¢/kWh for 86 to 97% solar, compared to the diurnal systems valve of 6.7 to 7.1¢/kWh for 59 to 63% solar).

With this analysis in mind, the results of the system simulations shown in Table 8 lead to the following conclusions, for an aquifer system:

1. Use of the unimproved evacuated tube collector results in at most a slight improvement in system performance over the flat plate collector system. In some cases, the evacuated tube collector may even cause a decrease in system performance.

2. Use of the advanced CPC collector results in a major improvement in system performance compared to flat plate or evacuated tube collectors. With the advanced CPC collector, required collector area for a given system performance level is reduced by 35% from the area required for flat plate or evacuated tube collectors.

3. Use of central receivers or parabolic troughs results in a 10% additional improvement over CPC collector performance in Madison, and 20% in Copenhagen.

4. With the assumed component costs, the minimum breakeven points for aquifer storage, including the storage component, are 6-7.5¢/kWh. The minimum breakeven costs for diurnal storage, which always occurs at minimum solar fraction, are 4.8 to 6.5¢/kWh. For a larger solar fraction (of at least 60%) this increases to 5.8 to 7.7 ¢/kWh. At the larger solar fractions the aquifer system is almost always more cost effective.

5. Differences in system sizing and economics among the three locations are relatively minor. This is true partly because of the three locations, the city with the most severe winters (Madison) is also the city with the most sunlight. Use of parabolic troughs and central receivers were found to be most advantageous in Copenhagen, because their ability to track the summer sun provides greater performance benefit in that high-latitude location.

6. The storage efficiency remained constant at 68% for all systems. The aquifer efficiency is dependent on the aquifer temperature profile and on the control system only, and is independent of system size. (Note that with a different control system, it is possible for the effective aquifer efficiency to drop to 61%. This depends on system assumptions).

7. The system performance reported here is significantly poorer than the performance reported in the preliminary analysis (Section 5.1). This is largely due to a change in the radiation processor algorithm. The preliminary analysis assumed anisotropic tilting and 20% ground reflectance. Ground reflectance was set equal to zero in these later results. There was also a small error in the SASS code which was since corrected.

5.4 Sensitivity Analysis

System sensitivity was analyzed with respect to four parameters: aquifer size, distribution losses, back up power delivery system, and aquifer heat exchanger. The sensitivity analysis was performed only for flat plate and CPC collector systems in Madison. Results for flat plate collector systems are presented in Table 9.

Table 9. Sensitivity Analysis for Aquifer System Performance

Coll. Area (1000 m^2)	Aquif. Vol (1000 m^3)	Solar Fractn.	Diurnal Solar Fractn.	Breakeven Costs (Cents/KWH) (Diurnal)	(Stor.)	(Total)
Maximum Aquifer Volume Varied						
150.	691.	.969	.639	7.4	6.7	7.2
150.	500.	.866	.639	7.4	7.0	7.3
150.	300.	.765	.639	7.4	7.6	7.4
150.	100.	.655	.639	7.4	19.9	7.7
Distribution Losses Varied						
Distribution Efficiency = 0.97						
150.	691.	.969	.639	7.4	6.7	7.2
Distribution Efficiency = 0.84						
150.	650.	.857	.611	7.7	8.4	7.9
Distribution Efficiency = 0.71						
150.	599.	.745	.575	8.2	11.2	8.9
Return Temperature Varied						
Return Temperature 40.						
150.	691.	.969	.639	7.4	6.7	7.2
Return Temperature 50.						
150.	691.	.951	.603	7.8	6.3	7.3

5.4.1 Aquifer size

Aquifer size is a hard parameter to optimize because the actual aquifer cost will depend on the number of wells drilled. The cost figure of $\$20/m^3$ is in reality only an approximate cost. If the main storage well turns out to have insufficient capacity, the only way to increase that capacity will be to drill a second well, which will provide a large increase in storage capacity, but also a large jump in cost. Therefore aquifer sizing depends on the capacity of the individual wells. If a given aquifer system is reasonably close to the desired storage capacity, it will not be worth increasing its size.

Table 9 presents system performance for a variety of aquifer sizes. It may be seen that, excluding very small aquifers, performance increases linearly with increase in aquifer size. This increase in system performance per unit volume may easily be calculated as the product of water heat capacity, maximum temperature drop between storage aquifer and cool well, and aquifer storage efficiency. For the system shown here, that product is 24.3 kWh/m^3 (88.MJ/m^3).*

Assuming a cost of $\$20/m^3$, system economics is found to improve with increasing aquifer size. However the breakeven cost for large aquifer systems does not vary significantly with minor variations in aquifer size. Consequently the exact dimension of the aquifer storage may vary depending on the available aquifer capacity.

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*The linear pattern breaks down for small aquifer volumes because the improved collector efficiency while operating at low temperatures and providing partial solar heat counteracts the extra heat provided by the small aquifer.

5.4.2 Distribution losses

It was mentioned above that distribution losses may have a major impact on system performance. For the high-density Madison district, it was estimated that distribution loses would amount to only 3% of the district load. By contrast, in the Inglestad test system, run on MINSUN, distribution losses amounted to 35% of the total load and were equal to half of the load of the buildings. The distribution system efficiency was only 65%.

Table 9 shows the effect of poor distribution efficiency on system performance. System heat delivery drops sharply as distribution efficiency drops. Note that for a distribution efficiency of 71%, the aquifer system delivers only slightly more heat than a diurnal solar system that did not have large distribution losses. This suggests that, for low-density districts, dispersed diurnal storage systems may be preferable to a central system.

5.4.3 Backup power delivery system

In the case system design, heat delivery is assumed to take place at 52°C, with a return temperature of 40°C. The need to provide high-temperature heat may sharply decrease collector efficiency, especially for flat plate collectors. An alternative arrangement which would permit greater use of low-temperature solar heat in partially meeting the district heating load could significantly improve system performance.

In the base case design, a booster heater is introduced between the storage tank and the distribution system, which boosts the distribution temperature to 52°C. Since the return temperature is 40°C, this means that the storage tank supplies energy to the system so long as its temperature is above 40°C.

Alternative designs are possible. One alternative is to build the booster heater directly into the storage tank, keeping the storage at 52°C constantly. This may save on the cost of heaters, and may also make system control easier, but will prevent use of solar energy at any temperature below 52°C. On the other hand, the backup fuel supply could be completely separated from the district heating system. In this case, the solar district heating system could continue to supply heat to the buildings, even when tank temperature dropped below 40°C,with the separate backup system supplying the remainder.

The analysis shown in Table 9 shows that for an annual-cycle system, the effect of the backup power configuration is not important. Annual-cycle systems are already designed to provide nearly all the building's heat at temperatures greater than 52°C. The advantage (or disadvantage) of alternative backup system designs only occurs during the brief periods when the backup system is needed. Consequently, it only changes the performance of the solar heating system by 1 or 2%.* But for diurnal systems, which rely heavily on backup power, the backup configuration can significantly change system performance. The effects of building the booster heater directly into the storage tank only caused a 2% drop in annual-cycle system performance, but caused a 6% drop in diurnal system performance.

5.4.4 Aquifer heat exchanger

The design of the heat exchanger between the solar collection system and the aquifer is found to have a major impact on system performance.

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*Note that the performance of annual cycle systems, especially those with flat plate collectors, could be significantly improved by lowering the system delivery temperature in the distribution network.

In the original design (Figure 3), the aquifer heat exchanger is assumed to be located inside the diurnal storage tank. Aquifer water was assumed heated from 42°C to 85°C while being pumped from the cool storage well to the hot storage well. The storage tank is cooled in the process. However the storage tank is not allowed to cool below 79.4°C while supplying heat to the aquifer. Once the storage tank temperature reaches 79.4°C the tank is assumed to be too cool to provide the 85°C heat required by the aquifer. (In fact the SASS algorithm is designed so that the diurnal storage tank is frequently heated to 90°C or more in order to provide 85°C heat for the aquifer). The result of this design is that the collectors must operate at 80°C or higher throughout the summer months.

With a more sophisticated heat exchanger, or a stratified diurnal storage tank, it would be possible to drive the diurnal tank temperature much lower. If, for instance, it were possible to pump water directly from the collector/storage loop into the aquifer, it would be possible to pump the entire contents of the diurnal tank at 85°C into the hot storage well, and refill the tank with 42°C water from the cool storage well. This would represent a heat exchange effectiveness of 100% between collector and aquifer. In practice, it is not possible to introduce water from the collector loop directly into the aquifer, but an effective heat exchanger may allow the storage temperature to be driven much lower than 80°C while still heating aquifer water to 85°C.

An analysis was made of system performance assuming that the diurnal tank temperature could be driven down to 64.4°C while the aquifer was being charged with 85°C water. Results showed an improvement in the performance of flat plate collector systems of nearly 10%. The required collector area for a 95% solar system in Madison was reduced from 150,000 m^2 to 130,000 m^2. Such an improvement still assumes a heat exchange efficiency of only 50% between the collector loop and the aquifer, so still further improvements based on better heat exchangers may be found. The effect of the heat exchanger on aquifer system efficiency may be compared to the effect of backup system configuration on the efficiency of diurnal systems. In each case system output is improved by permitting solar collection at lower temperatures.

With an advanced CPC collector, the effect of operating temperature is less important. The improved aquifer heat exchange to 50% efficiency was found to cause only a 2% improvement in system performance with CPC collectors. The conclusion is therefore that careful attention should be payed to the aquifer heat exchange configuration in flat plate collector systems, but less so for advanced CPC collectors.

5.5 Annual Cycle Systems With Buried Storage Tank

Because computer simulations for solar energy aquifer storage systems are not generally available, a comparison has been made between aquifer storage systems and annual cycle storage in conventional storage tanks. Should the behavior of solar systems with storage tanks prove similar to aquifer systems, then a standard design code for annual cycle systems such as MINSUN might be used for preliminary sizing of aquifer systems as well.

Annual cycle systems with tanks were designed using both the original SASS design code and MINSUN. System size and performance as calculated with the SASS simulation are presented in Table 10. The system designs in Table 10 are all based on the SERI optimization criteria[1]. The criteria state that the optimum storage size is at the point of "unconstrained operation", the point at which storage is large enough to store all excess collected solar energy. The economic optimum will either be an annual cycle system at the unconstrained point or else a diurnal system. Table 10 presents the performance of both unconstrained annual systems and diurnal systems.

Table 10. Performance, Sizing, and Economics for Systems with Storage Tanks

Coll. Area (1000 m^2)	Storage Vol (1000 m^3)	Solar Fractn.	Diurnal Solar Fractn.	Breakeven Costs (Cents/KWH) (Diurnal)	(Stor.)	(Total)
Madison - Flat Plate Collector						
100.	560.	.905	.524	6.1	8.2	7.0
110.	650.	.969	.550	6.4	8.6	7.4
Madison - Advanced CPC Collector						
70.	500.	.890	.524	6.0	7.8	6.7
75.	600.	.964	.565	6.0	8.4	7.0
Copenhagen - Flat Plate Collector						
140.	450.	.950	.639	7.6	8.9	8.0
Copenhagen - Parabolic Trough						
75.	450.	.916	.629	6.0	9.6	7.1
80.	450.	.965	.650	6.1	8.7	7.0
Boston - Parabolic Trough						
70.	450.	.940	.586	6.8	8.8	7.5

A comparison between Table 10 and the aquifer systems of Table 8 reveals that systems with storage tanks require smaller collector arrays to achieve the same performance as aquifer systems. With flat plate collectors, the collector array is reduced by approximately 30% when a storage tank is used in place of an aquifer. For parabolic troughs, the reduction in collector size is 10%. The tank storage volume, however is roughly comparable to the required aquifer storage volume.

The major reason for this difference in system performance and sizing has to do with the collector temperature and the aquifer heat exchanger. In a conventional annual storage system, the storage temperature would gradually increase from a minimum value in the spring to a maximum value in the fall. Also, the heat exchange effectiveness between collector and annual storage is 100% since the same water may be circulated between the collector and the annual storage tank. By contrast, in the base-case aquifer design, the collectors must operate at or near the maximum temperature for the entire summer, so long as heat is being stored in the aquifer. Because of the ineffective collector-to-aquifer heat exchange, the collector temperature must be 80°C before aquifer storage is possible. If a 100%-effective heat exchanger were possible between the collector loop and the aquifer, the performance of aquifer systems would be comparable to systems with annual storage tanks.

A second difference between the aquifer and tank storage systems concerns storage losses. In the aquifer system, storage efficiency is determined by the aquifer temperature profile. In tank systems, losses are determined by a storage loss calculation. Comparable results may be achieved only when the storage tank losses are set so that the storage efficiency is comparable to the aquifer. It turns out that the tank storage efficiencies for systems simulated in Table 10 are higher than the aquifer efficiency.

The conclusion is that the existing annual storage solar simulation code (such as MINSUN-SASS) should not be used to size aquifer systems, or should be used only for very rough system sizing. The conventional annual storage simulations cannot capture the essential features of the aquifer systems, especially the heat exchange properties between the collector and aquifer.

An attempt was made to use the MINSUN optimizer to design annual-cycle systems for comparison with the SASS code designs of Table 10. It was found that the MINSUN optimizer frequently does not size systems near the unconstrained point. This is due to two factors. First, in the standard MINSUN run, storage excavation and installation costs are high, resulting in a much higher effective storage cost than the nominal $35/m^3 (which accounts only for tank material costs). Consequently MINSUN is much more likely to select systems with lower storage volume. Secondly, for systems in which annual storage is a bare breakeven proposition, there is no clear-cut economic optimum. As discussed elsewhere[1] system output increases linearly with increasing storage volume, up to the point of unconstrained operation. In this near-breakeven situation, diurnal systems, unconstrained annual cycle systems, and intermediate systems are found to all have equivalent economics. In this case, the MINSUN optimizer frequently selects an intermediate storage size, even though a diurnal storage system or an unconstrained annual cycle system is slightly more favorable economically.

A complete discussion of system optimization is presented in the Appendix. When storage tank material costs were set at $12/m^3, MINSUN did in fact select an optimum system near the point of unconstrained operation, with collector and storage sizes comparable to those in Table 10. For a storage cost of $20/m^3, MINSUN selects an intermediate point, and with a cost of $35/m^3, MINSUN selects a diurnal system. This is in comparison with 10¢/kWh backup fuel. Again, the reason is high storage excavation and installation costs in MINSUN.

A complete and detailed optimization analysis and parameteric sensitivity study of the Fox River Valley Project with underground tank seasonal storage is presently underway, utilizing the latest MINSUN III code version. Results of this analysis will be reported separately at a later date.

6. CONCLUSIONS

In this study of the U.S.A. National Test Case, a solar seasonal aquifer storage system for the Fox River Valley Project,the following has been accomplished:

1. A computer simulation code has been developed for analysis of aquifer system designs which is comparable to MINSUN.

2. Several configurational designs - operational strategies have been developed and compared.

3. Simulations and optimum designs have been selected and presented for five collector types, and for the cities of Madison, Boston, and Copenhagen.

4. Criteria have been developed for the optimum aquifer size. It has been found that the ideal aquifer system has an aquifer large enough to store all collected solar energy, but that the actual aquifer size may reflect the availability of space in the individual aquifer.

5. Sensitivity analysis has identified two system design features which have a major impact on system performance and economics: the distribution system and the aquifer heat exchanger efficiencies.

Further work on the U.S.A. National Test Case will require more specific information on system configuration and hardware. In particular, detailed designs must be developed for collector piping and the distribution network, in order to properly assess distribution losses. Investigation of available heat exchange equipment for use in charging the aquifer, and estimation of alternative heat exchanger performance and costs, is also necessary. Finally, the possibility of integrated total energy system design--which uses central receivers or trough collectors to generate electricity as well as space heat--may be worth investigating in an annual cycle system.

As more detailed system designs become available, the SASS code and design procedure can be utilized to generate specific aquifer system size and performance. The final state in system design for an aquifer storage system can, however, only take place after aquifer wells have been drilled and the available aquifer characteristics and storage volume has been assessed for a specific site.

Advanced versions of MINSUN, capable of modeling aquifer systems and systems with both diurnal and seasonal storage, are expected to be developed as part of the IEA Task VII activities, and may be applied to future analyses of solar systems with seasonal storage in aquifers.

APPENDIX
MINSUN AND THE SERI DESIGN METHODS

This appendix will address two issues concerning simulation methods for the design of solar heating systems. The first will be a validation of the SASS design code against MINSUN. The second concerns experience with the MINSUN optimizer and the SERI optimization criteria.

A. Validation of the SASS code against MINSUN

The original SASS simulation is a code very similar to MINSUN. Like MINSUN, it uses a daily step simulation. Like MINSUN, it accepts pre-processed radiation data to find insolation on a tilted collector surface. Compared to MINSUN, the SASS code has both advantages and disadvantages. For the purpose of this study, there are three specific advantages of the SASS code that are worth highlighting.

1. The SASS code is a much simpler program than MINSUN. The algorithm may be listed in less than 4 pages of computer printout. Consequently it is very easy to modify.

2. SASS is already constructed to simulate diurnal, as well as annual storage systems. As explained above, simulation of a diurnal storage tank is presently necessary in the simulation of solar energy aquifer storage systems. Diurnal systems are also worth including in the optimization process.

3. Instead of a computerized optimization code, SASS permits user-interactive system design. In running SASS, the user enters a series of collector and storage sizes. The simulation then prints a one-line summary of the performance of each system. This permits a more accurate exploration of system sizing options and design trade-offs than can be provided with a computerized optimizer.

Conversely, MINSUN permits considerably more detail, precision, and flexibility in the modeling of real solar systems with seasonal storage. This is true for both the design of subsystems and in the economic and performance analyses. In addition, MINSUN can be driven through a sequence of runs to effectively model performance and cost surfaces over a range of input variables. Recent versions of MINSUN also have the capability to directly produce data for three dimensional plots of cost and performance surfaces.

In the initial comparison between MINSUN and SASS, some discrepancies were found based on the algorithm used for analyzing radiation data. The SASS radiation processor differs from the UMSORT program in the following ways.

1. The SASS radiation processor is written only for flat plate collectors.

2. The SASS processor uses an anisotropic tilting algorithm, developed by John Hay, for analyzing diffuse radiation.[16] MINSUN uses the more standard isotropic tilting formula.

3. The SASS radiation processor assumes 20% ground reflectance of solar radiation, and assumes that reflected ground radiation is receivable by a flat plate collector. The MINSUN processor assumes zero ground reflectance, even for flat-plate collectors. (This is justified for large central collector arrays where only the outer rows may experience significant ground reflectance).

There were also slight differences in the calculation of delivered solar energy to the load between MINSUN and SASS. In this case, the SASS routine was modified slightly.

In order to make the SASS simulation comparable with MINSUN, the following steps were taken.

1. The SASS code was modified to run using the MINSUN UMSORT output, instead of its own radiation processing algorithm. This permits SASS to be run for any collector that can be modeled by MINSUN, using the same data for solar collector performance that MINSUN uses.

2. The SASS radiation processor was also modified and run using the same assumptions as the MINSUN processor in calculating flat plate and evacuated tube collector performance.

The results of the two modified SASS codes - the one with UMSORT data and the other with its own modified radiation processor - were then compared to single-point MINSUN runs. The case used for this comparison was the U.S. National Test Case, The Fox River Valley Project, with an annual cycle storage tank system. A comparison of results is presented in Table 11. The results are found to be within 1% of each other.

It is concluded that the modified SASS code and the MINSUN code provide equivalent results in the simplified analysis of annual cycle system performance.

B. The MINSUN optimizer and the SERI design criteria

In Section 5.5 above, some mention has been made of the SERI optimization criteria. This criteria states that optimal annual cycle systems will be sized at the point of "unconstrained operation", the point at which storage is large enough to store all heat collected in the summer. If the unconstrained point does not represent the optimum, than the optimum point will be a diurnal system. This is not strictly true, for there are a few cases in which a system with intermediate storage size will be the optimum. But these intermediate optima are rare and should be viewed with some suspicion.

In running the MINSUN optimizer, it was found that occasionally an intermediate point was chosen as the system optimum. This raised some concern that perhaps the SERI optimization criteria was in error. However, it turned out that those intermediate optima were selected only when annual storage represented a "bare breakeven" proposition. Consequently, the system economics did not vary much with storage size. In this case,MINSUN would frequently optimize at a point that was technically non-optimal.

Table 11. Validation of SASS Simulation Code

Performance for the U.S. National Test Case, with an annual storage tank system, according to MINSUN, according to SASS with UMSORT input, and according to SASS with its own modified radiation processor.

Collector Area (1000 m^2)	Storage Volume (1000 m^3)	Solar Fraction MINSUN	SASS/ UMSORT	SASS
Madison - CPC				
199	40	.885	.898	.894
93.7	40	.647	.659	.651
98.8	519.	.983	.974	.967
80	600	.977	.970	x
100	300	.842	.854	x
Boston - FPC				
100	40	.592	.606	.603
100	400	.921	.916	x

Following are two examples, drawn from experience with the U.S. National Test Case: One is for a CPC system in Madison, Wisconsin. MINSUN was run using the same input parameters as was presented in the Inglestad test run of MINSUN, with modifications only to input the data for the U.S. National Test Case. In addition, the cost of storage was reduced from $35 to $15/m^3. (With $35/m^3 storage, MINSUN optimized to a system with minimal storage volume, apparently because high evacuation and construction costs were found in addition to the tank material costs.)

For this case, the MINSUN optimizer came up with the following size:

COLLECTOR	98,736 m^2	STORAGE	519,239 m^3
SOLAR	95%	TOTAL COST	\$3.796 million

Using SASS and the SERI optimization criteria, one would obtain instead a collector size of 80,000 m^2 and the storage volume of 600,000 m^3 for the unconstrained point, and a solar fraction of 95%.

This unconstrained point was run on MINSUN as a single point calculation. It was found that the TOTAL COST parameter was \$3.791 million, slightly less than the cost given by the MINSUN optimizer.

In another case, a flat plate collector system for Madison was sized with MINSUN, this time with \$25/m^3 storage costs. With a starting guess of 100,000 m^2 collector and 400,000 m^3 storage,MINSUN optimized to the following point:

COLLECTOR	138,747 m^2	STORAGE	399,574 m^3
SOLAR	88%	TOTAL COST	\$6.5295 million

The unconstrained point, according to SASS, would be 110,000 m^2 collector and 600,000 m^3 storage. The solar fraction is 93.5%.

When the unconstrained point was run on MINSUN the total cost was found to be \$6.999 million, which is significantly higher than the MINSUN optimum costs.

However the true optimum in this case turned out to be a system with minimal storage. MINSUN was run with a collector of 138,747 m^2 a storage of 50,000 m^3. The resulting solar fraction was 68%, and the cost parameter $5.933 million. Next, MINSUN was run to select the optimum system, but with an initial guess of 40,000 m^3 storage. Now MINSUN optimized to a minimum storage system with 180,000 m^2 collector, 50,000 m^3 storage, and a cost parameter of $5.724 million.

A similar case occurred with the Inglestad system that was sent out as a MINSUN uniform test case. For the input values used in the Inglestad test, MINSUN was run by the Solar Energy Research Institute, and found to optimize at 3500 m^2 collector and 3200 m^3 storage, as it did in the actual test. However, with only a slight change in the starting collector and storage size, the optimum point was found to be 5474 m^2 collector and 12192m^3 storage. This latter point turned out to be an unconstrained annual cycle system, and had very slightly lower costs than the original optimum point.

Several other runs with MINSUN resulted in an optimum point at an intermediate storage size. In each case, a single point calculation was performed with MINSUN for the point of unconstrained operation found by SASS and for a system with minimal storage. In all but one instance, either the unconstrained system or the system with minimal storage turned out to be an improved optimum over the point selected by MINSUN. In the one exception, MINSUN did find an intermediate optimum that was better than the unconstrained point, but the difference in total system cost was negligible.

The conclusion is that none of the MINSUN runs have cast doubt on the validity of the SERI optimization criteria.

Based on this experience, two ways to improve the performance of the MINSUN optimization routine are suggested:

1. The MINSUN routine could possibly be modified to take advantage of the SERI optimization criteria. If the MINSUN routine were directed to check the unconstrained point and the point of minimum storage, cases in which an inferior optimum point is selected might be avoided.

2. In cases where annual storage is a bare break-even proposition and system economics is relatively unchanging with storage size, the user needs to know that he has a wide range of feasible design choices, rather than one optimum. In this case, MINSUN could inform the user that there are several systems with equivalent cost, so that the user may choose based on the desired solar fraction and storage size. As it is now, the MINSUN optimizer simply reports a single system sizing.

An alternative approach, which has been used[17], and is being used in current analyses, is to drive the MINSUN simulation program through a sequence of runs for ranges of selected variables,and to plot cost and performance curves or surfaces (3-dimensional surfaces can be generated) from which an optimum design can be selected according to cost and solar fraction criteria specified by the user. This more user-interactive design methodology provides the designer with the necessary perspective of system cost and performance over an appropriately wide range, which is clearly lacking in the built-in MINSUN optimization routine.

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